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(article starts on next page)

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RESEARCH ARTICLE

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Economic assessment of advanced biofuel production via gasification using cost data from the GoBiGas plant

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Abstract

This paper describes an economic analysis of the GoBiGas plant, which is a first-of-its-kind industrial installation for advanced biofuel production (ABP) via gasification, in which woody biomass is converted to biomethane. A previous technical evaluation of the demonstration unit confirmed that it is technically feasible to construct advanced biofuel production plants, using commercially available and widely used components. Thus, significant cost reductions for equipment cannot be expected as a consequence of learning effects. However, the equipment itself accounted for <20% of the total investment cost at GoBiGas and there exists the potential to reduce the production cost through learning how to assemble the process and reduce project-specific costs. The analysis shows that a plant with capacity of 200 MW of biomethane is an attractive scale for future stand-alone ABP plants with respect to limiting the production cost. For a 200-MW ABP plant operated using forest residues as fuel, the production cost for biomethane is estimated at approximately 600 SEK/MWh, (60€/MWh, 75US$/MWh), which is equivalent to 5.4 SEK/liter gasoline [0.54 €/liter, or 2.5USD per gallon (9.9 SEK/€, 8 SEK/USD)], where the feedstock accounts for about 36% of the production cost. The most significant uncertainty factors pertaining to the estimated production costs are expected to relate to: trade conditions; the location of the installation; and the local price of feedstock. Thus, there is some potential for implementing cost-competitive ABP systems of smaller capacity if low-grade feedstocks (eg, waste-derived woody biomass) can be utilized, and/or if the unit can be integrated with the already existing infrastructure.

KEYWORDS

advanced biofuels, bio-refinery, demonstration plant, economic assessment, gasification, GoBiGas

1 | INTRODUCTION

In this report, cost data for a first-of-its-kind, demonstration plant for advanced biofuel production (ABP), namely the GoBiGas plant, are analyzed to derive an estimate of the production costs of biofuels in a commercial-scale ABP plant of similar type. The GoBiGas project was the direct result of ambitious efforts to replace fossil fuels with renewable alternatives, and it reflects the political goals of both the European Union and the Government of Sweden. The GoBiGas plant was built in the harbor area of Gothenburg, Sweden, by Göteborg Energi, which is an energy company own by the

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municipality of Gothenburg, and the projects were supported with 222 million SEK by the Swedish Energy Agency. In the GoBiGas process, woody biomass is converted to produce biomethane. The purpose of the project was to contribute to fulfilling the local targets to reduce local emissions, such as soot particles from buses, as well as restricting greenhouse gas emissions. The GoBiGas project included two phases, whereby the first phase involved the construction of a demonstration plant capable of producing 20 MW of biomethane and the second phase involved the construction of a commercial plant with a production capacity of about 100 MW. Due to unfavorable market conditions, the municipality of Gothenburg decided in 2017 not to initiate the second phase of the project and not to build the commercial plant. This work is therefore based on the experience and data from the demonstration plant with 20 MW of production, which is referred to as the "GoBiGas plant."

With the goal of building a second commercial unit, the demonstration plant was constructed so as to fulfill the following performance goals inherent to a commercial unit:

- Biomass-to-biomethane efficiency of 65%
- Total efficiency of 90%
- Production for 8000 hours per year
- Feeding gas to the national gas grid with a composition of: methane, >94%$_{vol}$; hydrogen, <2%$_{vol}$; carbon dioxide, <2.5%$_{vol}$; nitrogen, <3.5%$_{vol}$; carbon monoxide, <0.1%$_{vol}$; ammonia, <20ppm$_{vol}$; and dew-point <−8°C at 70 bar.

The GoBiGas plant comprises two distinct sections: (a) the gasification section, where the biomass is converted to gas; and (b) the methanation section, where the gas is conditioned and synthesized into CH_4. The methanation section of the GoBiGas plant was designed with the levels of redundancy and safety adopted in petrochemical industries, enabling continuous operation for about 4 years without major revision. This can be compared to the ambition related to time between revisions for large-scale biomass boilers in the pulp and paper industry, which is typically in the range of 12-18 months. The equipment used in the gasification section is similar to that of conventional fluidized bed boilers used in combined heat and power (CHP) plants,[1] and the ambition for operation without major revision for the gasification section of the GoBiGas plant was 6-12 months. As a consequence, the gasification section was constructed with little redundancy and limited possibilities for service during operation.

The GoBiGas process encompasses gasification of biomass in a dual fluidized bed (DFB) gasifier, gas conditioning, and methanation. The main process steps are illustrated in Figure 1 and have previously been described in detail,[1-3] whereby the technical feasibility and performance have been analyzed. Briefly, the GoBiGas plant is a first-of-its-kind unit in which the whole production chain, including a DFB gasifier and methanation, is combined in a demonstration plant. The DFB technology, which has previously been applied in commercial plants for heat and power production[4] on a smaller scale, was scaled up twofold for the GoBiGas

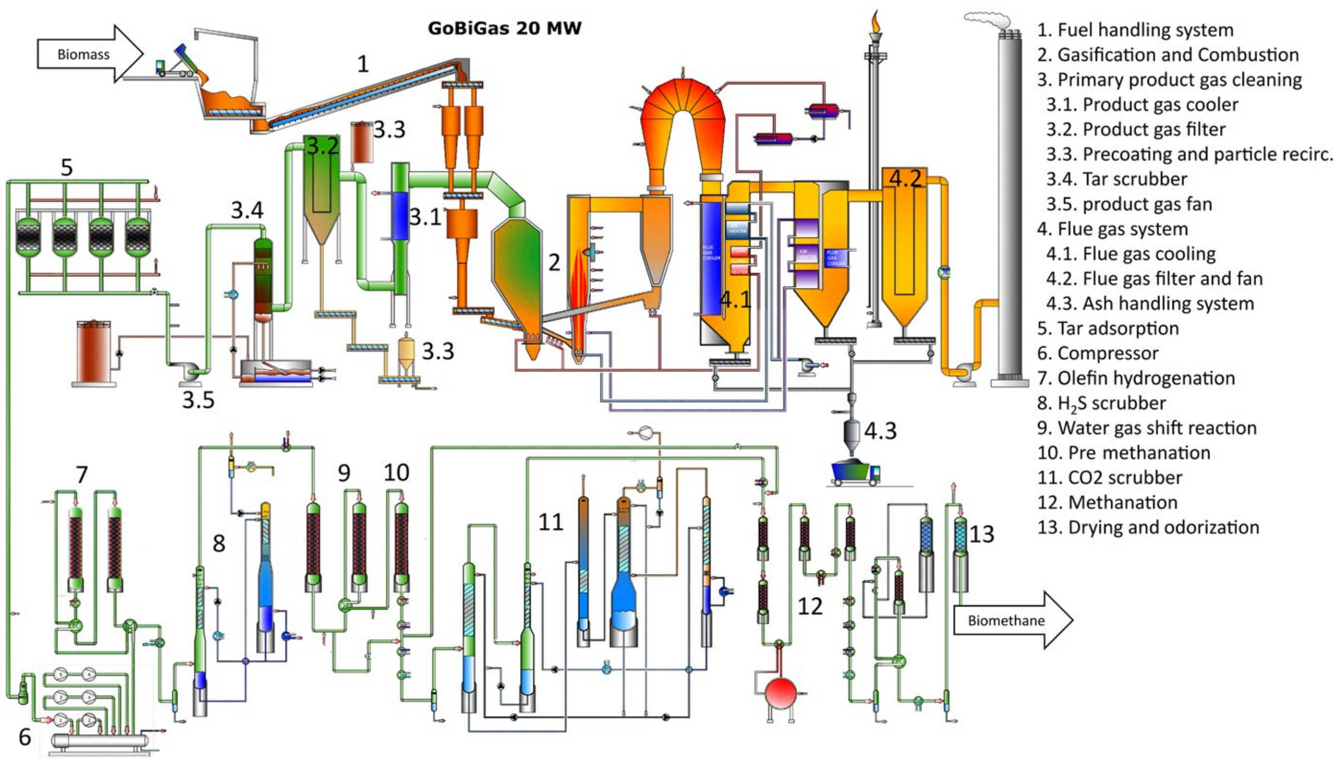

FIGURE 1 Schematic of the GoBiGas plant, indicating the major process steps

plant. The methanation technology, which has been used in commercial plants that are based on fossil fuels,[5,6] had to be scaled down significantly to match the DFB gasifier. An analysis of the performance of the process concluded that it is technically feasible to reach a biomass-to-biomethane efficiency of up to 70% based on the lower heating value (LHV) and dry ash-free (DAF) fuel.[1-3]

An initial breakdown of the investment cost for the GoBiGas plant based on the project summary has been reported elsewhere,[2] showing that a significant proportion of the investment was related to aspects specific to the site or the project. Therefore, a more detailed analysis is performed in this study, so as to generate a more general and realistic estimate of the investment costs of an ABP plant for the production of biomethane. Furthermore, the aggregated investment cost is here complemented with costs related to the operation of the plant, so as to estimate the total cost of producing biomethane with this type of technology. Based on the production cost for the demonstration plant, the production of a commercial-scale unit can be estimated using scale factors (SFs) for the different costs. Thus, one can define how the costs differ when building a plant with a different production capacity, as well as the potential changes to the costs linked to lessons learnt.[7] The production cost for an ABP plant has previously been investigated based on simulated processes.[8,9] The present work is instead based on real cost data from the GoBiGas project, which means that uncertainties related to simulation of the process are avoided.

As described in the technical review of the GoBiGas project,[1] one of the main lessons that has been learned is that the equipment can be assembled using mainly commercially available components that have already reached a level of maturity corresponding to the n-th numbered installation. In the GoBiGas project, the major technical component that had not yet reached a mature commercial state was the gasifier. However, evaluation of the technology, combined with the parallel experience accrued from operation of the semi-industrial plant built at Chalmers, showed that the gasifier could be built using the already existing mature boiler technology. This is in-line with recent modifications made at other plants based on the same gasification technology, but used for heat and power production, and where required availability of the plant when using intended feedstock, forest residue, has been demonstrated, for example, at the plant in Senden.[4] The reactor design used for the gasifier in the GoBiGas project is used mainly for either heat and power or only heat production in pulp and paper mills and in district heating systems. In Sweden alone, more than 100 of these units have been installed, and around the world more than 1000 units are in operation. This means that the technology used for constructing the gasification section of the plant can be assumed to have a level of maturity similar to that of commercial CHP plants based on the fluidized bed technology, and that significant cost reductions due to learning cannot be expected. However, as GoBiGas is a first-of-its-kind plant, these types of gasification and methanation technologies have been combined, and there is still potential to reduce the production cost by learning how better to combine and operate the different process sections.[1]

As there are no other plants for comparison, the investment cost for GoBiGas is here compared with the investment cost for CHP plants. CHP plants were chosen for the comparison as a relevant number of plants using biomass as feedstock have been built in Sweden within the last decade. The information on the CHP plants comes from a database that covers all the power plants in Europe, which was developed at Chalmers and is continuously being updated.[10] A biomass CHP plant constitutes a complexity level similar to that of the gasification section of the GoBiGas plant, and is here used to visualize how project-related features, such as site-specific cost, price levels of commodities, and performance goals, can influence the investment cost for a large-scale, biomass-based production plant.

The objectives of this work were to present reference cost data based on the GoBiGas project and to estimate the production costs for advanced biofuels generated via gasification on a commercial scale. To achieve this, investment and operational costs were estimated based on data accrued from the GoBiGas demonstration plant. Aggregated reference data and SFs for a commercial APB plant have been established based on a detailed study of the investment costs of the GoBiGas plant, in combination with the previously published technical review of the process.[1-3]

2 | REFERENCE DATA AND SCALE FACTORS

The production cost for a commercial-scale ABP plant is here estimated based on the: (a) investment cost; (b) plant development costs; and (c) operating costs, according to Equations (1-11) in Table 1. Where the investment cost, C_{Inv}, for process section i of a plant of size, P, is estimated based on the investment cost of process section i of the GoBiGas plant, $C_{\mathrm{Inv\ ref},i}$, with production capacity $P_{\mathrm{ref}} = 20$ MW and scale factor SF_i. The produced biomethane is traded based on the energy content of the gas (MWh), and the specific cost, c, is therefore presented in SEK/MWh$_{\mathrm{prod}}$. The specific capital cost related to the depreciation, c_{dep}, is estimated based on the expected lifetime (LT) of the plant and the expected yearly full-load hours (FLH) of the plant. The specific capital cost related to the interest from the investment, c_{int}, is estimated based on the interest factor, θ_{int}, which is based on the plant LT and interest rate, int. Some development is expected to be required during the LT of the plant, and the specific cost related to that development, c_{dev}, is estimated based on a development factor, θ_{dev}.

TABLE 1 Summary of equations used

Factor	Formula and Equation no.	Unit
Investment cost for process section i	$C_{\mathrm{inv},i} = C_{\mathrm{Inv,ref},i}\left(\frac{P}{P_{\mathrm{ref}}}\right)^{SF_i}$ Equation (1)	[SEK]
Investment cost	$C_{\mathrm{inv}} = \sum_i C_{\mathrm{Inv},i}$ Equation (2)	[SEK]
Specific cost, depreciation	$c_{\mathrm{dep}} = C_{\mathrm{inv}} / (P * \mathrm{LT} * \mathrm{FLH})$ Equation (3)	[SEK/MWh$_{\mathrm{prod}}$]
Specific cost, interest	$c_{\mathrm{int}} = C_{\mathrm{inv}}\theta_{\mathrm{int}} / (P * \mathrm{LT} * \mathrm{FLH})$ Equation (4)	[SEK/MWh$_{\mathrm{prod}}$]
Interest factor	$\theta_{\mathrm{int}} = LT * \frac{\mathrm{int}}{1-\left(1+\mathrm{int}\right)^{-LT}} - 1$ Equation (5)	[-]
Development cost	$c_{\mathrm{dev}} = C_{\mathrm{inv}}\theta_{\mathrm{dev}} / (P * \mathrm{LT} * \mathrm{FLH})$ Equation (6)	[SEK/MWh$_{\mathrm{prod}}$]
Annual operating cost for cost item j	$C_{\mathrm{ope},j} = C_{\mathrm{ope\,ref},j,\mathrm{ref}}\left(\frac{P}{P_{\mathrm{ref}}}\right)^{SF_j}$ Equation (7)	[SEK/year]
Specific operating cost j	$c_{\mathrm{ope},j} = C_{\mathrm{ope},j} / (P * \mathrm{FLH})$ Equation (8)	[SEK/MWh$_{\mathrm{prod}}$]
Total specific operating cost	$c_{\mathrm{ope}} = \sum_j c_{\mathrm{ope},j}$ Equation (9)	[SEK/MWh$_{\mathrm{prod}}$]
Specific fuel-related cost	$c_{\mathrm{fuel}} = c_{\mathrm{fuel,ar}}\left(1 - \frac{Y_m}{1-Y_m}\frac{2.4}{\mathrm{LHV}_{\mathrm{dry}}}\right)\frac{1}{\eta_{\mathrm{prod}}}$ Equation (10)	[SEK/MWh$_{\mathrm{prod}}$]
Total specific production cost	$c_{\mathrm{prod}} = c_{\mathrm{dep}} + c_{\mathrm{int}} + c_{\mathrm{dev}} + c_{\mathrm{ope}} + c_{\mathrm{fuel}}$ Equation (11)	[SEK/MWh$_{\mathrm{prod}}$]

The annual operational cost related to each cost item, j, for GoBiGas, that is, $C_{\mathrm{ope\,ref},j}$, is used to estimate the annual operating cost of a plant with production capacity P. The specific operational cost for each cost item, $c_{\mathrm{ope},j}$, and total specific operating cost, c_{ope}, are estimated based on the plant production capacity and expected FLH. The cost items included in the operational costs relate to costs for personnel, maintenance costs, cost for consumables and waste products, as well as some other costs but excluding the cost of the biomass used as feedstock for the plant, which is calculated separately. The specific fuel-related cost, c_{fuel}, is estimated based on the moisture content, Y_{m}, and the $\mathrm{LHV}_{\mathrm{DAF}}$ value of the fuel, as well as the efficiency of conversion of the biomass to biomethane, η_{prod}, the fuel cost per MWh as-received, $c_{\mathrm{fuel,ar}}$, and the heating value of dry fuel, $\mathrm{LHV}_{\mathrm{dry}}$. Summarizing all the specific costs yields the total specific production cost, c_{prod}.

The investment cost for the different process sections for GoBiGas and the estimated reference investment cost, $C_{\mathrm{Inv\ ref},I}$, are summarized together with the applied scale factors in Table 2. $C_{\mathrm{Inv\ ref},I}$ is the estimated cost when extraordinary costs due to site-specific conditions have been subtracted.

The investment cost of the project accumulated during the period 2011-2014. The cost paid in Euros (€) has here been calculated using an average exchange rate for the period of 9.1 SEK for 1.0 €. The site that was chosen for the GoBiGas plant entailed the imposition of some restrictions on the project. For example, most of the plant had to be built indoors, and a massive explosion wall had to be constructed owing to the proximity of a production plant for district heating. This entailed project-specific costs for the explosion wall (B4 in Table 2), as well as increased costs for piping, mechanical equipment, and insulation (D in Table 2). These costs are here subtracted from the reference costs used for the analysis, as it is unlikely that future versions of the plant will have these features. Likewise, the cost related to services (E in Table 2) has been reduced in the analysis, as the engineering costs for the GoBiGas project were higher than what might be expected for future plants.

The site also came with several advantages, in that it was located close to the local district heating network, the natural gas grid, and an existing local system for providing cooling water, and it had the possibility to recover low-temperature heat for district heating via heat pumps. Furthermore, the plant could be incorporated into the existing environmental permit for the neighboring plant used for heat production. The amount of capital tied up in the GoBiGas plant feedstock and other inventories is negligible and, therefore, is not included in the investment total. The same is assumed to apply to larger-scale units. For all ABP plants that will be built, local conditions and demands will provide numerous challenges or benefits that will either add to or reduce the costs of the plant. These costs cannot be predicted using generalized cost estimates.

As concluded from the technical review, a commercial ABP plant based on gasification should incorporate an external fuel reception and storage facility for wood chips, a fuel dryer, and a steam cycle (including a turbine), in addition the process equipment installed at GoBiGas. The cost for the GoBiGas project, as summarized above, only includes the internal fuel handling system and a connection to the previously existing fuel reception and handling system, which is shared with a pellet-fired boiler. Therefore, the cost for the external fuel handling system should be included when estimating the cost of a commercial plant. These costs have been estimated from the costs that apply to similar existing commercial installations, recalculated to the same cost year as GoBiGas 2014, as summarized in Table 3.

TABLE 2 Investment costs and scale factors for all process sections of the GoBiGas plant; $P = 20$ MW. Any changes in cost for future plants are highlighted in bolded numbers

Process systems		Cost GoBiGas, kSEK	Reference cost 20 MW, $C_{inv,i}$, kSEK	Scale factor low	Scale factor	Scale factor high
1	Fuel handling system	50 400	50 400			
1.1	External fuel feeding system			0.50	0.60	0.70
1.2	Internal fuel feeding system, including lock hoppers			0.40	0.50	0.60
2	Gasification and Combustion	29 490	29 490			
2.1	Reactors and refractory			0.60	0.70	0.80
2.2	Condensate treatment and steam generation			0.50	0.60	0.70
3	Primary product gas cleaning	23 780	23 780			
3.1	Product gas cooler			0.60	0.70	0.80
3.2	Product gas filter			0.60	0.70	0.80
3.3	Precoating and particle handling system, including bed material storage and feed			0.50	0.60	0.70
3.4	Product gas scrubber			0.60	0.70	0.80
3.5	Product gas fan and secondary cooler			0.60	0.70	0.80
3.5	Analyzers			0.30	0.40	0.50
4	Flue gas system	18 930	18 930			
4.1	Flue gas cooler			0.70	0.80	0.90
4.2	Flue gas filter and flue gas fan			0.70	0.80	0.90
4.3	Ash handling system			0.60	0.70	0.80
5	Tar adsorption (AC filter)	10 620	10 620			
5.1	Activated carbon beds			0.70	0.80	0.90
5.2	Regeneration system			0.50	0.60	0.70
6	Compressor	34 590	34 590	0.60	0.70	0.80
7	Olefin hydrogenation	9060	9060	0.60	0.70	0.80
8	H_2S scrubber	9150	9150	0.60	0.70	0.80
9	Water-Gas Shift reaction	5290	5290	0.60	0.70	0.80
10	Premethanation	5150	5150	0.60	0.70	0.80
11	CO_2 scrubber	17 570	17 570	0.60	0.70	0.80
12	Methanation	19 410	19 410	0.60	0.70	0.80
13	Drying and odorization	4970	4970	0.60	0.70	0.80
TOTAL COST, PROCESS SYSTEMS, SEK		238 410	238 410			
Auxiliary equipment and project costs		**Cost GoBiGas, kSEK**	**Refrence cost 20 MW, $C_{inv,i}$, kSEK**	**Scale factor low**	**Scale factor**	**Scale factor high**
A	Auxiliary equipment	146 520	146 520			
A.1	Flare			0.60	0.70	0.80
A.2	Hot water system			0.40	0.50	0.60
A.3	Instrumentation and Control system (DCS)			0.30	0.40	0.50
A.4	Power distribution			0.40	0.50	0.60
A.5	Electrical and Instrument installation			0.30	0.40	0.50
A.6	Compressed air system			0.50	0.60	0.70
A.7	Fire protection system			0.50	0.60	0.70

(Continues)

TABLE 2 (Continued)

Auxiliary equipment and project costs		Cost GoBiGas, kSEK	Refrence cost 20 MW, $C_{inv,i}$, kSEK	Scale factor low	Scale factor	Scale factor high
A.8	Inert gas system			0.50	0.60	0.70
A.9	Safety and security			0.30	0.40	0.50
A.10	Laboratory and sampling system			0.20	0.30	0.40
B	Civil	219 910	**178 960**[a]			
B1	Ground preparation			0.30	0.40	0.50
B2	Foundations			0.30	0.40	0.50
B3	Buildings, including lights			0.40	0.50	0.60
B4	Explosion protection walls			0.40	0.50	0.60
B5	HVAC			0.50	0.60	0.70
C	Structural steel	48 000	48 000	0.40	0.50	0.60
D	Piping. Mechanical equipment, and insulation	266 640	**213 312**[a]	0.50	0.60	0.70
E	Services	460 330	**368 264**[a]			
E1	Engineering			0.20	0.30	0.40
E2	Construction Services and Commissioning			0.20	0.30	0.40
E3	Start-up			0.20	0.30	0.40
E4	Other project services			0.20	0.30	0.40
TOTAL COST, AUXILIARY EQUIPMENT AND PROJECT COSTS		1 141 400	955 056			
TOTAL COST, GRAND TOTAL		1 379 810	1 193 466			

[a]Removed are those costs coupled to project-specific events that added costs that pertain specifically to the GoBiGas plant, including the building of an explosion wall, piping, and engineering costs.

To estimate the investment cost required for a commercial-scale plant based on the GoBiGas technology, SFs that describe how the cost changes with production capacity have been employed. For the gasification section of the plant, suitable SFs have previously been suggested.[8,9] For the reactors and other equipment used in the methanation section of the plant, data are available from larger fossil-based processes and provide relevant SFs.[11-14] These SFs are complemented with experience from the international consulting and engineering company Pöyry AB[15] and the project management and technology provider BioShare AB.[16]

To illustrate the uncertainties related to the effect of scale-up on the investment cost, estimates were also performed using a *high* SF, respectively *a low* SF, in order to allow comparisons with the base case. To place these uncertainties in perspective, a comparison is made with historic data relating to the initial investment costs of the relevant more mature technologies of commercial-scale CHP plants. The comparison between the CHP and ABP plants also serves to illustrate how the annual FLH influences the production cost and consequently, the profitability of the plant. The initial investment costs for a number of relevant commercial-scale CHP plants built and brought into operation within the past 10 years in Sweden are used for the comparison.[10,15]

TABLE 3 Estimated costs for equipment not included in the GoBiGas plant[15]

Process section	Reference cost, $C_{\text{inv ref},i}$, kSEK	Reference production capacity, P_{ref}, MW
Fuel handling	280 000	100
Belt dryer	60 000	100
Steam cycle	200 000	100

The specific investment cost (in SEK/MWh) for CHP plants is estimated by assigning the same value to both heat and power, as there is currently only a minor difference in the local market values of these products, and the capacity is calculated as heat plus power. For the initial investment cost of a CHP plant, the reference values for the *low*, *average*, and *high* cases are 900, 1400, and 2500 MSEK, respectively, for a 100-MW plant with SFs of 0.5, 0.6, and 0.7, respectively. This was considered as representative, given that these values lie within the range of the historic values for CHP plants. In this study, the reference CHP plant is assumed to have an efficiency of 35% electricity and 70% heat, based on the lower heating value of the received fuel with a moisture content of 45%. This corresponds to an efficiency of 31% electricity and 63% heat, based on fuel delivered dry instead of wet, and is similar to the efficiency value obtained if the efficiency is based on higher heating value; the economic lifetimes of the plants are assumed to be 20 years. In contrast to the advanced fuel production, the product output from the CHP plant is calculated as the sum of the heat and the power, as mentioned above.

The impact of annual FLH on the production cost related to the depreciation cost can be estimated from Equation 3. The ABP plant is assumed to be operated for 8000 FLH per year, while different cases are illustrated for the CHP plant, as the operation of this type of plant is more dependent upon variations in the energy demand than is an ABP plant that can store its product.

The cost related to the interest part of the investment, C_{int}, is calculated as the cumulative annuity over the assumed economic lifetime minus depreciation. The interest rate is set at 2.5%, 5%, 7.5%, or 10%, which creates average cost related to interest over the economic lifetime of the plant of 28%, 60%, 96%, or 135%, respectively, relative to the initial investment cost. Even though the individual parts of an ABP plant are based on mature technologies, combining them into an ABP plant is novel. Therefore, a development-related investment cost, C_{dev}, is included. This represents equipment and system updates that are not covered by the regular annual maintenance and are arbitrarily assumed to contribute an additional 10% to the total investment cost over the economic lifetime of the plant.

The operating costs for the GoBiGas plant have been analyzed in detail and are here presented as four aggregated categories for: (a) personnel; (b) maintenance; (c) consumables and waste products; and (d) other costs. The SF that is applied to the investment cost, as well as the different operating costs are summarized in Table 4. The *Personnel cost*, *Maintenance cost*, and *Other cost* are listed so as to provide an insight into the actual costs that result from the GoBiGas demonstration plant and, based on this yield, a reference for estimating the production cost of a commercial ABP plant.

Operation of the GoBiGas plant requires about 28 full-time employees, with three operators being required onsite at all times. The *Personnel costs* are here estimated at 29 million SEK per year. A low SF is assumed, as the number of persons needed to operate a much larger plant is expected to be similar to the number required at the demonstration plant, given that there will be a similar level of process complexity.

The *Maintenance cost* category mainly relates to the cost incurred during the revision of the plant. Operation of the GoBiGas plant is stopped each year for about 1 month to allow for revision. For a plant that annually reaches 8000 FLH, the time period between the planned maintenance stops will most likely be extended from the present 12-18 months, which is in-line with the revision period for a pulp mill. About 60% of the revision cost is related to the gasification section of the process, in that the bulk of the revision relates to maintenance of the refractory lining and heat exchangers. The scaling factor for the maintenance cost is, therefore, assumed to be equal to the ratio of the area to the volume of the reactors (SF of 0.67). About 40% of the maintenance cost is related to the methanation part of the process, where regular inspections and maintenance of the pressure vessels account for most of the cost. While a somewhat lower SF could be expected for this part of the process, for the sake of simplicity and to avoid underestimating the maintenance cost, the same SF is applied to the maintenance costs linked to the two parts of the process.

The category of *Consumables and waste products* includes the material and energy consumed during operation, as well as the waste products that incur costs for the operation and are based on continuous operation during the month of December 2017. In addition to the biomass feedstock, the following materials are used during operation: nitrogen, as the purge gas; olivine sand, as the bed material in the gasifier; rapeseed oil methyl ester (RME), as the scrubber liquid to remove tar components; calcium carbonate, which is used as a precoating material for the particle filter in the product gas line; potassium carbonate, which is added to control the gas quality during gasification; activated carbon, as an adsorbent to remove light aromatic compounds, such as BTX (Benzene, Toluene and Xylene), from the product gas; different catalysts used in the methanation section to condition and synthesize the gas to biomethane; and fresh water, which is mainly used for steam production. The energy carriers consumed during the production are mainly: electricity, most of which is used for compression of the gas; and natural gas, which is used for heating during the start-up of the process. The waste products from the plant include waste water, fly ash, and bottom ash. As described previously,[1] the costs for consumables can be significantly reduced through:

1. the introduction of a steam cycle, which would render the plant self-sufficient for electricity;
2. the introduction of a self-cleaning heat exchanger or scrubber agent distilled from inherent tar products, which would eliminate the need for RME;
3. inherent regeneration of carbon beds, which would significantly reduce the need for active carbon; and
4. the implementation of an optimized heat integration system, which would remove the residual need for natural gas.

In Table 4, both the present costs and the predicted costs for a future commercial plant are listed. It should be noted that the cost associated with the removal of aromatic hydrocarbons, which in the GoBiGas plant is accomplished by RME

TABLE 4 Aggregated costs and scale factors for different costs related to the operation of an ABP plant. The untreated cost estimate based on GoBiGas is included in italic text to indicate the estimated changes. An efficiency of 70% are assumed for further analysis and the fuel costs for this case are therefore highlighted in bold text.

Cost	**Scale factor**	***Capital costs for the GoBiGas plant***	**Estimated capital costs for a 20-MW reference plant**
Initial Investment Cost, $C_{\mathrm{Inv\ 20\ MW}}$		*MSEK/20 MW*	MSEK/20 MW
Reactor systems (from Table 2)	0.68	*238*	238
Auxiliary Equipment and Project Costs (from Table 2)	0.44	*1141*	955
Steam cycle, external fuel handling and drying, (from Table 3)	0.67	—	182
Total		*1380*	1375
Operating Costs, excluding feedstock, $c_{\mathrm{ope\ 20\ MW}}$		***SEK/MWh***[a] $c_{ope\ 20\ MW}/(P_{20\ MW}\ FLH)$	**SEK/MWh**[b] $c_{\mathrm{ope\ 20\ MW}}/(P_{\mathrm{20\ MW}}\ \mathrm{FLH})$
Personnel	0.10	*181*	181
Maintenance	0.67	*89*	89
Consumables and waste products	1.00	*131.5*	55.1
Electricity		*37.6*	0[b]
RME		*31.7*	0[b]
Activated carbon/BTX removal		*8.5*	10
Other		*53.6*	45.1
Other costs	0.67	*26.5*	26.5
Total		*428.0*	351.6

	Cost of ingoing fuel	**Fuel-related costs in SEK/MWh biogas**				
		Dry biomass to biomethane efficiency %, LHV				
Feedstock cost	**SEK/MWh**	**55**	**60**	**65**	**70**	**75**
Pellets[c]	250	448	411	379	**352**	329
Forest residue[d]	170	276	253	234	**217**	203
Recovered wood fuels[e]	110	194	178	164	**153**	143
Recovered wood fuels[e]	50	88	81	75	**69**	65

[a]Based on 8000 full-load hours per year and a 20-MW biomethane production plant.
[b]Based on expected changes for commercial plants, as suggested by the technical review of GoBiGas.[1]
[c]Pellets, 10% moisture.
[d]Forest residue, 45% moisture.
[e]Recovered wood, 18% moisture.

scrubbing and active carbon beds, can be significantly reduced (as described above) by employing an alternative strategy; the estimated cost for this is, in Table 4, incorporated into the cost for BTX removal for a commercial plant.

The category of *Other costs* includes all the remaining costs, such as overhead costs and license fees. This is a comparatively small category and the SF is arbitrarily assumed to be 0.67.

The chemical efficiency of an ABP plant has previously been evaluated.[2,3] Here, an efficiency of 70% based on the energy of the dry part of the delivered biomass is assumed. It should be noted that while a further increase in efficiency is technically possible, increasing the efficiency level above 70% would probably increase the investment cost; for the sake of simplicity and to avoid increasing the uncertainty of the analysis, this case is not considered here. The potential for sellable district heating would be in the order of 10%, subject to the plant being located in proximity to a district heating network. Since location is not specified, the heat is not given any value in the analysis.

3 | RESULTS AND DISCUSSION

As described previously,[1] an ABP plant can be constructed from components that are commonly used in current commercial processes. This means that at the component level, the technology has already reached the n-th installation and learning will only pertain to the assembly of these parts into a new system. Thus, the cost reduction potential linked to further learning is considered to be modest. In addition, a major part of a gasification-based ABP plant will consist of similar reactor systems regardless of whether the selected product is methane (the biofuel produced at GoBiGas) or some other biofuel, such as methanol, dimethyl ether (DME), mixed alcohols or Fischer-Tropsch crude (which resembles a long distillate from a light crude oil, but without impurities). This means that the investment costs associated with the GoBiGas plant are relevant also for these other types of ABP plants.

Figure 2 shows the investment costs of ABP and CHP plants in relation to installed capacity. The investment cost of the ABP plant is based on the investment cost of the GoBiGas plant and the bars indicate how the investment cost changes as the estimated SFs are changed by ±0.1. The investment costs for recently built biomass-based CHP plants are indicated as black dots, and the scaling curve is derived based on a 100-MW CHP plant as described in previous section. Even though a biomass-fired CHP plant comprises a mature technology that has reached the n-th number of its kind status, the initial investment costs for the different plants vary considerably. The historic data for CHP plants do not follow the economy of scale based on the 100-MW unit, especially not the smaller units, and there is a large variation in investment cost (range, 10-20 MSEK/MW) even for those plants that have a similar core technology and production capacity. A contributing factor is that a low investment cost has been prioritized over electrical efficiency, fuel flexibility, and availability (in terms of the number of redundant systems included) for some plants. It should be noted that many of these plants have been designed based on the demand for district heating rather than based on the demand for electricity production.[8,16] Based on this and the fact that some local markets offer similar price levels for heat and power, these products are weighted equally in Figure 2. The GoBiGas was built with the goals of optimizing biogas production, availability, and fuel flexibility. Based on the CHP analogy, it can be argued that there is strong potential to reduce the investment cost of an ABP plant through amending the goals set for performance and fuel flexibility in the GoBiGas plant, or through utilization of local synergies, for instance, to produce district heating as a by-product. Especially in the case of small-scale plants, the investment cost can vary widely, as illustrated by the data from CHP plants.

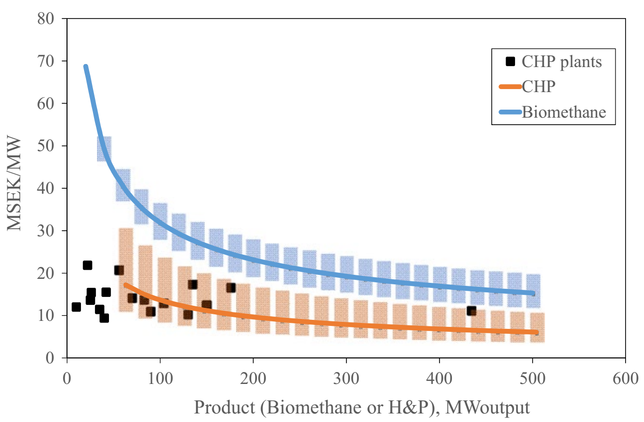

FIGURE 2 Initial investment cost per installed capacity (MW product) for advanced biofuel (biomethane) and CHP plants. The black dots represent the costs for a number of CHP plants built in Sweden after year 2010

The following analysis focuses on stand-alone ABP plants with high demands in relation to efficiency, fuel flexibility, and availability, as is the case for the GoBiGas plant. In addition, the following comparison with CHP is made using an estimated investment cost that is based on the scaling of a 100-MW plant, whereby the range of SFs was adjusted to encompass all plants with capacities >80 MW. As shown in Figure 3, the investment cost for a stand-alone ABP plant will be roughly twice that for a CHP plant. Thus, for an ABP to be economically competitive with CHP plants, when they are competing for the same feedstock, a higher total profit per MW of installed capacity has to be reached for ABP plants to compensate for the high investment cost. This is of course subject to the market price of the produced products, the operating cost, and the total production throughout the expected economic lifetime of the plant. The total production throughout the lifetime, in turn, depends on the efficiency and annual number of FLH of the plant. If there is a restriction on the demand for the products produced by a plant this will restrict the FLH of the plant, which is the case for CHP plants, whereby the demand for both heat and power fluctuates greatly over the year.[17] This is illustrated in Figure 4, where the specific investment costs in terms of depreciation for ABP plants with 8000 FLH per year are compared with those for CHP plants with 1000, 2000, 4000, and 8000 FLH per year, respectively.

As concluded in the Nordic Energy Technology Perspective, a future scenario that entails a warmer climate could restrict Nordic CHP plants to about 2000 FLH per year, and a future scenario that entails extensive access to intermittent power, extensive variation management strategies, warm winters, and energy savings in buildings could impose a restriction as low as 1000 FLH per year for CHP plants.[17] With these scenarios, the specific investment cost for an ABP plant is much less than that for a CHP plant, thereby making ABP a competitive alternative to bio-CHP. However, with the 4000 FLH per year currently expected for most CHP plants, the specific investment cost will be similar to or lower than that of an ABP plant with the same production capacity. Moreover, if the CHP plant can offset the produced heat and

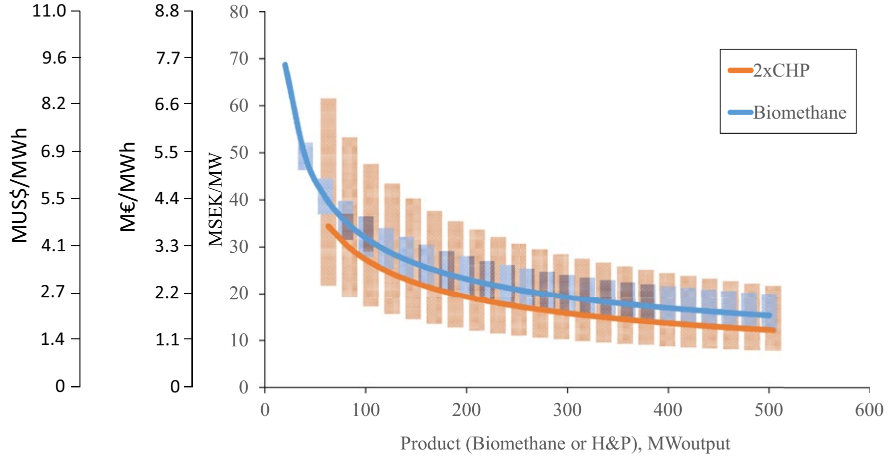

FIGURE 3 Initial investment cost per capacity (MW product) for an advanced biofuel (biomethane) plant, as compared with a twofold higher investment cost for a CHP plant, for different currencies. Exchange rates: 9.1 SEK per 1 € (average exchange rate during the project); and 1.25 US$ per 1 €

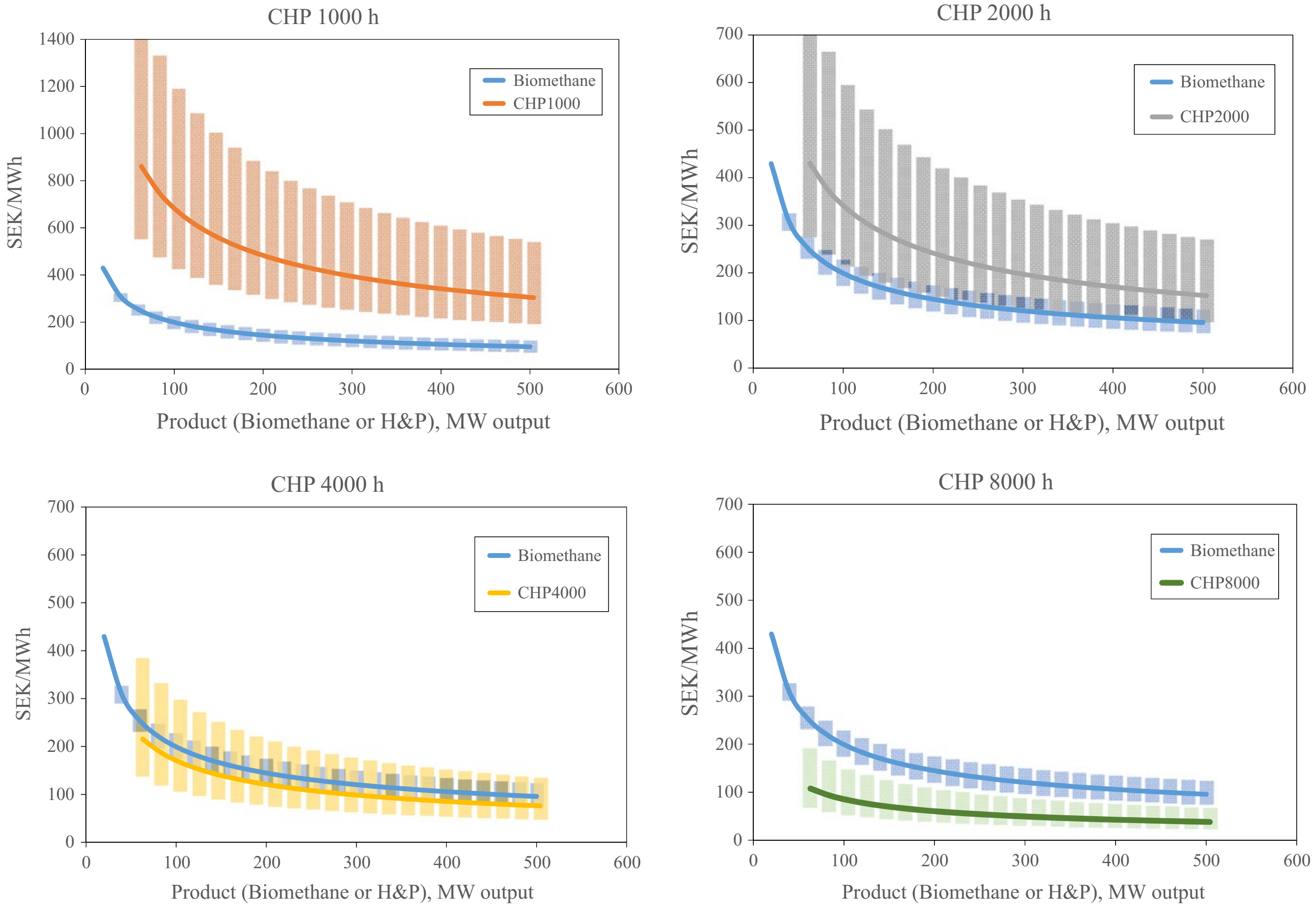

FIGURE 4 Depreciation cost divided by the expected production during the technical lifetime of the plant (20 years) for 8000 full-load-hours of the ABP-plant and 1000, 2000, 4000, and 8000 full-load hour (FLH) for the CHP plant. Note that the scale of the *y*-axis for 1000 FLH differs from the other cases

power over the entire year (8000 FLH) the specific investment costs for these plants will be significantly lower than those for an ABP plant.

The operating costs for the GoBiGas plant (ie, all costs excluding the investment-related financial costs), are illustrated as a function of the fuel price in Figure 5. The current operating costs for the GoBiGas plant using wood pellets as feedstock are indicated as an area, where the area is based on variations in feedstock prices, as well as the variations in plant operation in terms of availability, load, and efficiency. Previous investigations have shown that it is technically feasible to achieve a chemical efficiency for biomass-to-biomethane conversion of around 70%

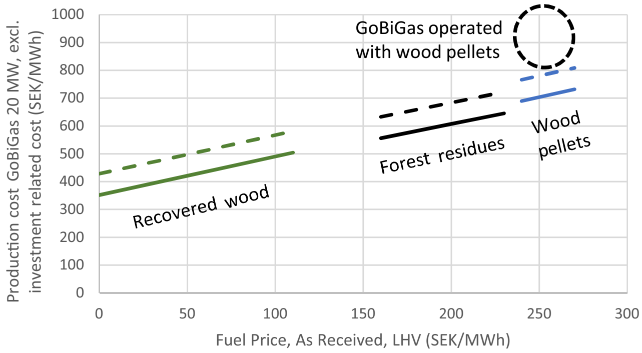

FIGURE 5 Total operating costs for the GoBiGas plant when optimized and complemented with a dryer, as well as the range of present production costs when using wood pellets. Fuel price is related to the lower heating value of the received fuel. Given that the fuels have different moisture contents, the lines are not continuous and have different slopes. The dashed lines represent an optimized case for GoBiGas with different fuels, while the solid lines represent an estimated reference plant (see Table 4)

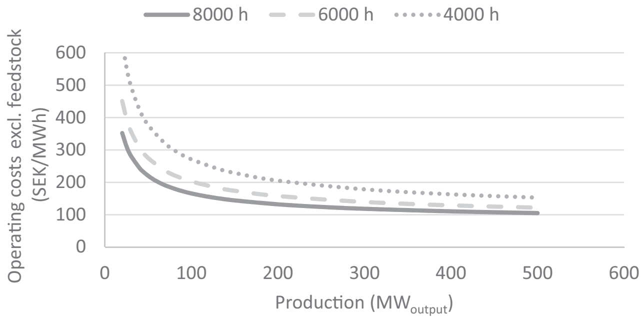

FIGURE 6 Operating costs (excluding feedstock costs) as a function of the production capacity for various full-load hours of operation of the plant

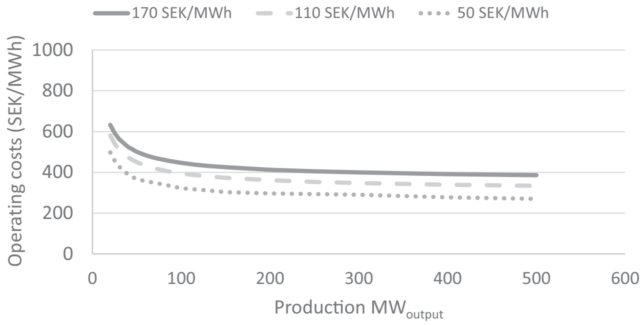

FIGURE 7 Operating costs as a function of the production capacity of the plant and price of feedstock, assuming an availability of the plant corresponding to 8000 full-load hours per year

for the plant, as compared to the current level of 55%-65% (for further details on how to optimize the process, see ref. 2,3). The operating costs estimated for operation at 8000 hours per year and a biomass-to-biomethane conversion efficiency of 70% are illustrated with a dotted line in Figure 5. A commercial plant could be further optimized for operational costs, mainly by including a steam cycle and eliminating the need to use large volumes of RME as scrubbing liquid (see Table 1). The operating costs estimated for a commercial ABP plant are indicated with a solid line in Figure 5. Note that the fuel price is specified as "as-received," which is the basis on which it is traded. This results in differences in the slope of the curve for the different fuels, as they can be expected to have different moisture contents, which are here assumed to be 10% for pellets, 45% for forest residue, and 18% for recovered wood waste. Furthermore, to achieve a conversion efficiency of 70%, the fuel is assumed to be dried to a moisture content of about 10%, using heat recovered from the process, before it is fed into the gasifier.[1] It can be concluded that with a plant capacity of 20 MW, the operating cost can be reduced by about 15% through switching from wood pellets to forest residues, and by as much as 40% if recovered wood is used.

The following analysis is based on using the estimated operating cost for a reference plant (solid line in Figure 5) to estimate the production cost of a commercial plant. The operational cost excluding the fuel cost, which is illustrated in Figure 6 as a function of the scale of the plant, is estimated using Equations (7-9) (Table 1). The operational cost including the fuel cost is illustrated in Figure 7, where the fuel cost is estimated from Equation 10.

Some of the operating costs, such as the costs for maintenance and personnel, can be expected to be more or less fixed yearly costs, which means that the specific operating cost can be expected to be strongly influenced by the number of FLH per year, as illustrated in Figure 6. The operating cost excluding the cost for the feedstock has the strongest effect on plants of smaller scale. This is mainly related to the personnel costs, which are proportionally higher for smaller-scale operations and are constant regardless of the availability, as the personnel are here assumed to be employed for the full year. This effect is, however, less prominent for FLH values >6000. If the personnel can be used for other purposes during part of the year, a production capacity >100 MW and a FLH >6000 should be considered as limiting the specific operating cost excluding the cost for the feedstock; as compared to a 20-MW unit, this cost is expected to be reduced by about 50%.

As shown in Figure 5, the cost of the feedstock has a strong impact on the production cost for a 20-MW unit, and this holds true also for units of larger scale, as illustrated in Figure 7, which shows the operating cost including the fuel cost. As expected, the cost of the feedstock becomes, in relative terms, more important as the scale of operation increases, and it represents about 65% of the operating cost for a plant with production capacity of 200 MW using biomass at a cost of 170 SEK/MWh. Thus, measures to reduce the fuel cost or increase efficiency will have strong impacts on the production cost for such a plant. However, for a 20-MW unit, the same fuel would only account for about 35% of the operating cost. This shows that measures to reduce the personnel and maintenance costs are more effective at reducing the operating cost.

TABLE 5 Estimated total production cost (including investment costs) for biomethane, using forest residues for feedstock (170 SEK/MWh based on lower heating value of received fuel with 45% moisture), 8000 FLH, 20-year economic lifetime, and 70% plant efficiency

	Commercial plant, 20 MW SEK/MWh	Commercial plant, 100 MW SEK/MWh	Commercial plant, 200 MW SEK/MWh
Capital cost, depreciation	430	199	145
Capital cost, interest (5%)	258	120	87
Development cost	43	20	15
Operation costs (excluding feedstock)	352	166	132
Feedstock cost	217	217	217
Total cost	1300	722	596

In Table 5, the estimated total production costs for an ABP plant with 70% efficiency are given for plants with 20, 100, and 200 MW, respectively, of biomethane production capacity. As shown in Figure 3 and in Figures 6 and 7, the cost reduction due to economy of scale for plants with capacities >200 MW plateaus (considering that the largest feasible plant size is around 500 MW ABP), and the benefit of progressing to a larger scale becomes increasingly uncertain. At this production capacity, the expenses for feedstock logistics and handling start to represent significant additional costs for most geographic locations. Thus, for a stand-alone APB plant of complexity similar to that of the GoBiGas plant, a production capacity of 200 MW represents a beneficial scale. In Table 5, forest residues are chosen as the feedstock in all the cases, which would be most relevant for these types of plants in the case of large-scale introduction of advanced biofuels. Here, it should be noted that the used costs relate to forest residue at its current price level in the Gothenburg region, which has a regional market situation with an excess of such feedstocks. As presented in Table 5, the production cost for biomethane in a plant with a production capacity of 200 MW is estimated as 596 SEK/MWh, corresponding to around 5.35 SEK/liter gasoline equivalents. The production costs for other types of biofuels produced via gasification and with performance goals similar to those for the GoBiGas plant, can be estimated based on the expected conversion efficiency for that biofuel. The cost of the feedstock changes according to Equation 10, while the other costs should be adjusted based on the change in production capacity related to the thermal input by adjusting the reference production capacity P_{ref}.

For a plant with a lower production capacity, alternative local feedstocks, such as recovered wood materials, could be an alternative. Under current pricing conditions, this offers the potential to reduce the total cost of a 100-MW biomethane plant to the same level as that of a 200-MW biomethane unit using forest residue. If one is aiming for even smaller scales of operation, cheaper feedstocks would need to be complemented with options for integration with existing industrial infrastructures, so as to reduce the investment cost and provide opportunities for sharing personnel. This could reduce the total production costs to competitive levels, similar to the strategy used for small CHP plants discussed above. It should also be noted, as evident from the comparison of the resulting feedstock costs for various production efficiencies (Table 4) with the total production cost (including investments), that plant efficiency has a limited effect on the total cost as long as fuel prices are at or below the price of forest residues.

4 | CONCLUSIONS

In the GoBiGas project, the production of an advanced biofuel in the form of biomethane has been demonstrated on the 20-MW scale. By analyzing the investment and production costs at the GoBiGas plant, relevant cost data for future investments in advanced biofuel factories have been derived. Using forest residues as the feedstock at the present regional price of 170 SEK/MWh (based on the lower heating value of revised moist biomass), this study predicts a production cost for biomethane of 596 SEK/MWh, corresponding to 5.35 SEK/liter gasoline equivalent, from a commercial plant with a nominal production capacity of 200 MW biomethane, when no excess heat is valorized.

Given that the gasification-based processes already contain components that are commercially available and used in many existing industrial processes, and the fact that the demonstration plant is designed to meet all the regulations pertaining to a commercial plant of this kind, the investment cost related to the equipment itself is unlikely to decrease dramatically due to learning. Instead, there is learning potential related to how the process is assembled and how one can plan and execute the project for constructing this type of plant. Furthermore, the main components of an ABP plant are similar regardless of the end product, making the outcomes relevant not only for biomethane (as produced at GoBiGas), but also for other advanced biofuels, such as methanol, dimethyl ether (DME), mixed alcohols, or Fischer-Tropsch products for which the estimated production cost and the plant production capacity need to be adjusted based on the expected conversion efficiencies of such fuels.

In specific cases, the production cost could be reduced further, subject to favorable local conditions that facilitate introduction of the technology. The investment cost could also be reduced by taking advantage of investments that have already been made in existing plants, such as fluidized bed boilers, which could be retrofitted so as to additionally produce advanced biofuels. This would create the opportunity to employ simplified process concepts in which a low investment cost is prioritized over high efficiency when excess heat from the ABP can be valorized. This would make it feasible to introduce the technology at smaller scale than is feasible for a stand-alone unit. Another opportunity to reduce the overall cost level comes from changing from biomass to waste-derived feedstocks, such as recovered wood that is free of impregnated chemicals and paint.

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